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23

Hard to Find Information (on Distribution System Characteristics and Protection)

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23.1 Overcurrent Protection

23.1.1 Introduction

The distribution system shown in [Fig. 23.1](#) illustrates many of the features of a distribution system making it unique. The voltage level of a distribution system can be anywhere from about 5 kV to as high as 35 kV with the most common voltages in the 15 kV class. Areas served by a given voltage are proportional to the voltage itself, indicating that, for the same load density, a 35 kV system can serve considerably longer lines. Lines can be as short as a mile or two and as long as 20 or 30 miles. Typically,

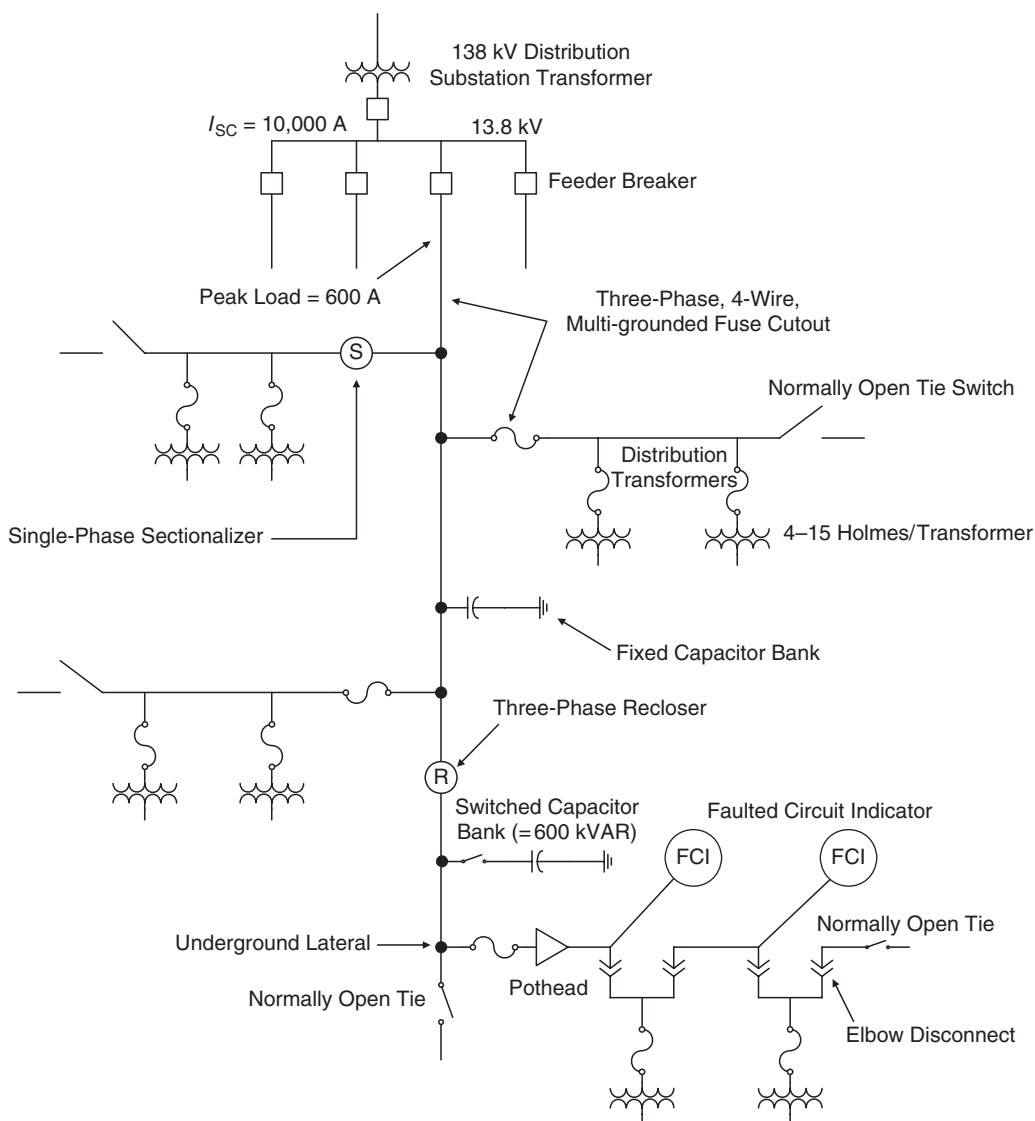


FIGURE 23.1 Typical distribution system.

however, lines are generally 10 miles or less. Short-circuit levels at the substation are dependent on voltage level and substation size. The average short-circuit level at a distribution substation has been shown, by survey, to be about 10,000 A. Feeder load current levels can be as high as 600 A but rarely exceed about 400 A with many never exceeding a couple of hundred amperes.

23.1.2 Fault Levels

There are two types of faults, low impedance and high impedance. A high impedance fault is considered to be a fault that has a high Z due to the contact of the conductor to the earth, i.e., Z_f is high. By this definition, a bolted fault at the end of a feeder is still classified as a low impedance fault. A summary of findings on faults and their effects is as follows.

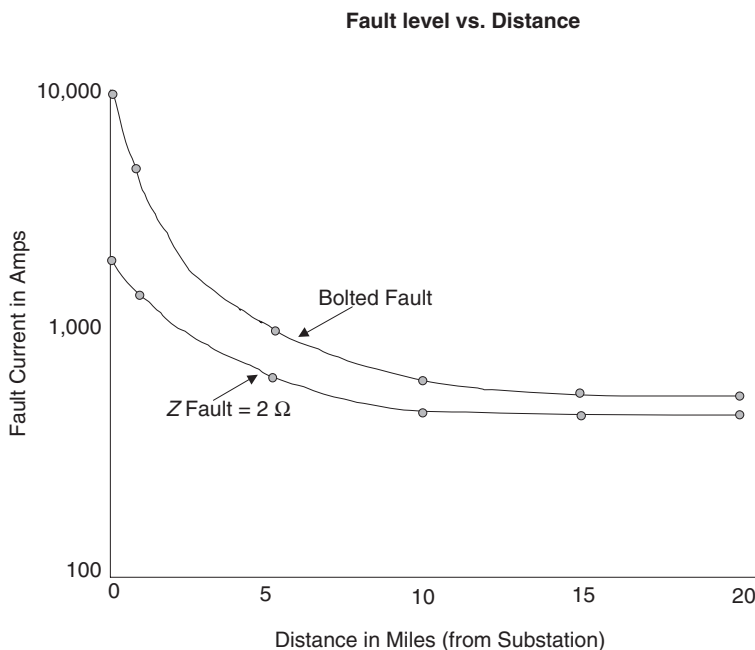


FIGURE 23.2 Low impedance faults.

23.1.2.1 Low Impedance Faults

Low impedance faults or bolted faults can be either very high in current magnitude (10,000 A or above) or fairly low, e.g., 300 A at the end of a long feeder. Faults that can be detected by normal protective devices are all low impedance faults. These faults are such that the calculated value of fault current assuming a “bolted fault” and the actual are very similar. Most detectable faults, per study data, do indeed show that fault impedance is close to $0\ \Omega$. This implies that the phase conductor either contacts the neutral wire or that the arc to the neutral conductor has a very low impedance. An EPRI study performed by the author over 10 years ago indicated that the maximum fault impedance for a detectable fault was $2\ \Omega$ or less. Figure 23.2 indicates that $2\ \Omega$ of fault impedance influences the level of fault current depending on location of the fault. As can be seen, $2\ \Omega$ of fault impedance considerably decreases the level of fault current for close-in faults but has little effect for faults some distance away. What can be concluded is that *fault impedance does not significantly affect faulted circuit indicator performance* since low level faults are not greatly altered.

23.1.2.2 High Impedance Faults

High impedance faults are faults that are low in value, i.e., generally less than 100 A due to the impedance between the phase conductor and the surface on which the conductor falls. Figure 23.3 illustrates that most surface areas, whether wet or dry, do not conduct well. If one considers the fact that an 8-ft ground rod sunk into the earth more often than not results in an impedance of $100\ \Omega$ or greater, then it is not hard to visualize the fact that a conductor simply lying on a surface cannot be expected to have a low impedance. These faults, called high impedance faults, do not contact the neutral and do not arc to the neutral. They are not detectable by any conventional means and are not to be considered at all in the evaluation of fault current indicators (FCIs) and most other protective devices.

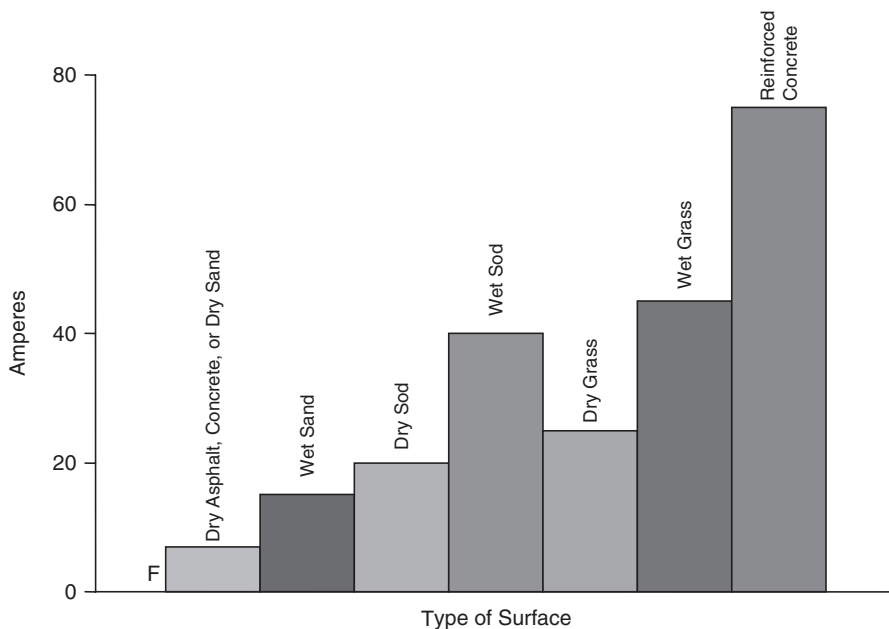


FIGURE 23.3 High impedance fault current levels.

23.1.3 Surface Current Levels

See Figure 23.3.

23.1.4 Reclosing and Inrush

On most systems where most faults are temporary, the concept of reclosing and the resulting inrush currents are a fact of life. Typical reclosing cycles for breakers and reclosers are different and are shown in [Fig. 23.4](#).

These reclosing sequences produce inrush primarily resulting from the connected transformer kVA. This inrush current is high and can approach the actual fault current level in many instances. [Figure 23.5](#) shows the relative magnitude of these currents. What keeps most protective devices from operating is that the duration of the inrush is generally short and as a consequence will not melt a fuse or operate a time delay relay.

23.1.5 Cold Load Pickup

Cold load pickup, occurring as the result of a permanent fault and long outage, is often maligned as the cause of many protective device misoperations. [Figure 23.6](#) illustrates several cold load pickup curves developed by various sources. These curves are normally considered to be composed of the following three components:

1. Inrush—lasting a few cycles
2. Motor starting—lasting a few seconds
3. Loss of diversity—lasting many minutes

When a lateral fuse misoperates, it is probably not the result of this loss of diversity, i.e., the fuse is overloaded. This condition is rare on most laterals. Relay operation during cold load pickup is generally the result of a trip of the instantaneous unit and probably results from high inrush. Likewise, an FCI

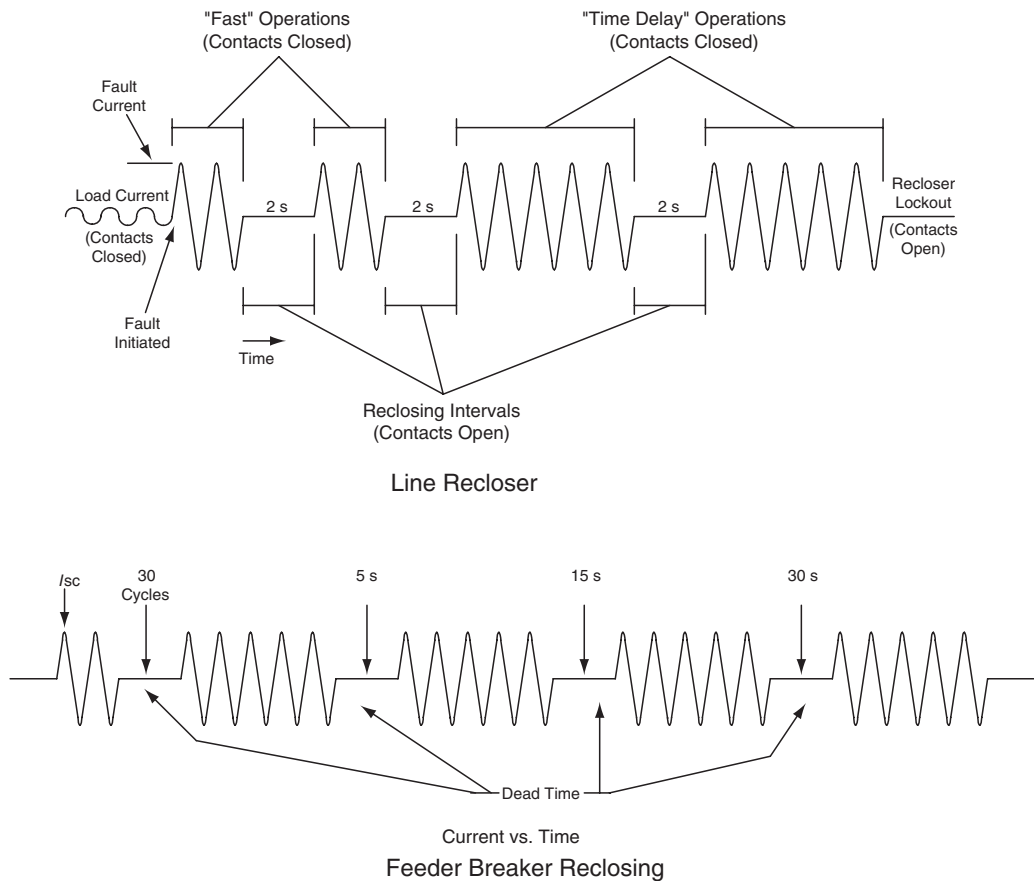


FIGURE 23.4 Reclosing sequences.

operation would not appear to be the result of loss of diversity but rather the high inrush currents. Since inrush occurs during all energization and not just as a result of cold load pickup, it can be concluded that cold load pickup is not a major factor in the application of FCIs.

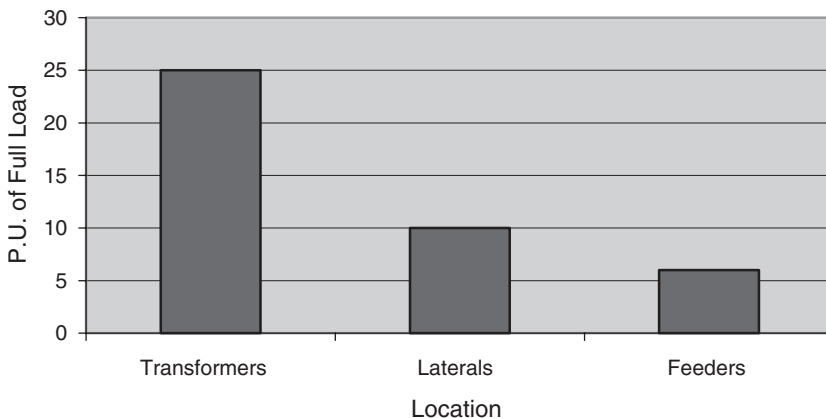


FIGURE 23.5 Magnitudes of inrush current.

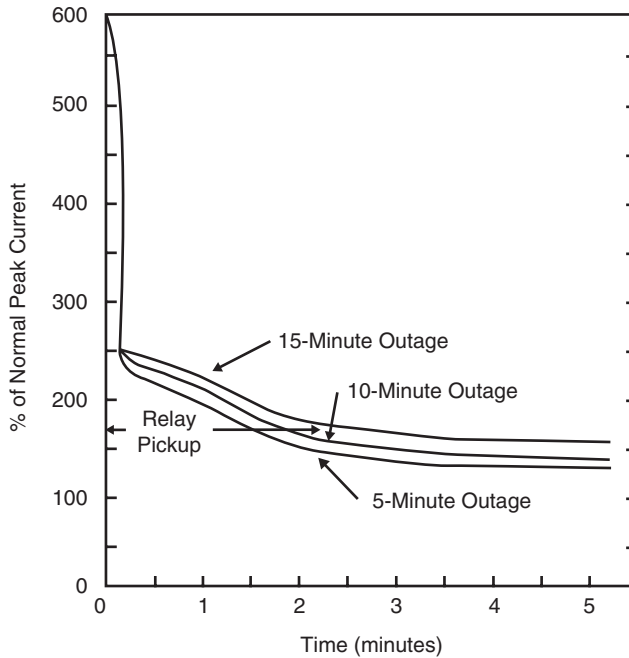


FIGURE 23.6 Cold load inrush current characteristics for distribution circuits.

23.1.6 Calculation of Fault Current

Line Faults

$$\text{Line-to-neutral fault} = \frac{E}{\sqrt{3}Z_{\ell}}$$

where Z_{ℓ} is the line impedance and $2Z_{\ell}$ is the loop impedance assuming the impedance of the phase conductor and the neutral conductor are equal (some people use a 1.5 factor).

$$\text{Line-to-line fault} = E/2Z_{\ell}$$

Transformer Faults

$$\text{Line-to-neutral or three-phase} = \frac{E}{\sqrt{3}Z_T}$$

$$\text{Line-to-line} = \frac{E}{2(Z_T + Z_{\ell})} \quad \text{where} \quad Z_{\ell} = \sqrt{R_L^2 + X_L^2}$$

$$Z_T = \frac{Z_T\% 10E^2}{\text{kVA}}$$

23.1.7 Current Limiting Fuses

Current limiting fuses (CLFs) use a fusible element (usually silver) surrounded by sand (Fig. 23.7). When the element melts, it causes the sand to turn into fulgerite (glass). Since glass is a good insulator,

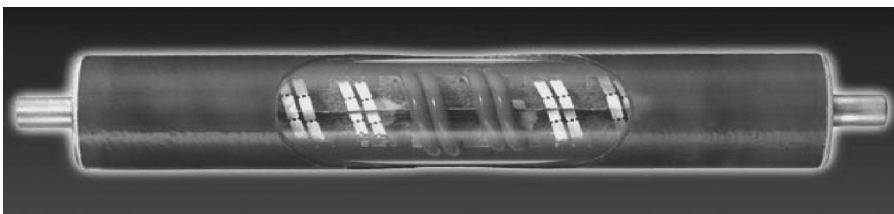


FIGURE 23.7 Full range current limiting fuse. (Courtesy T&B. With permission.)



FIGURE 23.8 Back-up CLF.

this results in a high resistance in series with the faults. This not only limits the magnitude of the fault but also the energy. All this can happen in less than a half cycle.

CLFs are very good at interrupting high currents (e.g., 50,000 A). They historically have had trouble (General Purpose, and Back-up) with low level fault currents and overloads, where the fuse tube melts before the element (i.e., these two fuses are not considered to be “full range,” since they do not necessarily interrupt low currents that melt the element). There are now “full range” CLFs in the market (see Fig. 23.7).

The three types of CLFs are defined as follows:

- General purpose—A fuse capable of interrupting all currents from the rated maximum interrupting current down to the current that causes melting of the fusible element in 1 h.
- Back-up—A fuse capable of interrupting all currents from the rated maximum interrupting current down to the rated minimum interrupting current (Fig. 23.8).
- Full range—A fuse capable of interrupting all currents from the rated maximum current down to any current that melts the element.

23.1.8 Rules for Application of Fuses

1. Cold load pickup.

After 15-min outage	200% for 0.5 s
	140% for 5 s
After 4 h, all electric	300% for 5 min

2. “Damage” curve—75% of minimum melt.
3. Two expulsion fuses cannot be coordinated if the available fault current is great enough to indicate an interruption of less than 0.8 cycles.
4. “T”-SLOW and “K”-FAST.
5. CLFs can be coordinated in the subcycle region.
6. Capacitor protection:
 - The fuse should be rated for 165% of the normal capacitor current. The fuse should also clear within 300 s for the minimum short-circuit current.

- If current exceeds the maximum case rupture point, a CLF must be used.
 - CLFs should be used if a single parallel group exceeds 300 kVAR.
7. Transformer
 - Inrush—12 times for 0.1 s.
 - 25 times for 0.01 s.
 - Self protected—primary fuse rating is 10–14 times continuous when secondary breaker is used.
 - Self protected—weak link is selected to be about 2.5 times the continuous when no secondary breaker is used (which means that minimum melt is in the area of 4–6 times rating).
 - Conventional—primary fuse rated 2–3 times.
 - General-purpose current limiting—2–3 times continuous.
 - Back-up current limiting—the expulsion and CLF are usually coordinated such that the minimum melt I^2t of the expulsion fuse is equal to or less than that of the back-up CLF.
 8. Conductor burn down—not as great a problem today because loads are higher and hence conductors are larger.
 9. General purpose—one which will successfully clear any current from its rated maximum interrupting current down to the current that will cause melting of the fusible element in 1 h.
 10. Back-up—one which will successfully clear any current from its rated maximum interrupting down to the rated minimum interrupting current, which may be at the 10-s time period on the minimum melting time–current curve.
 11. CLF—approximately 1/4 cycle operation; can limit energy by as much as 60 to 1.
 12. Weak link—in oil is limited to between 1500 and 3500 A.
 13. Weak link—in cutout is limited to 6,000–15,000 asymmetrical.
 14. Lightning minimum fuse (12T-SLOW), (25K-FAST).
 15. Energy stored in inductance $= \frac{1}{2} Li^2$.
 16. The maximum voltage produced by a CLF typically will not exceed 3.1 times the fuse rated maximum voltage.
 17. The minimum sparkover allowed for a gapped arrester is $1.5 \times 1.414 = 2.1$ times arrester rating.
 18. General practice is to keep the minimum sparkover of a gapped arrester at about $2.65 \times$ arrester rating.
 19. Metal oxide varistors (MOVs) do not have a problem with CLF “kick voltages”.

23.1.9 More Overcurrent Rules

1. *Hydraulically controlled reclosers* are limited to about 10,000 A for the 560 A coil and 6,000 A for the 100 A coil.
2. Many companies set ground minimum trip at maximum load level and phase trip at two times load level.
3. A *K factor* of 1 (now used in the standards) means the interrupting current is constant for any operating voltage. A recloser is rated on the maximum current it can interrupt. This current generally remains constant throughout the operating voltage range.
4. A *recloser* is capable of its full interrupting rating for a complete four-operation sequence. The sequence is determined by the standard. A breaker is subject to derating.
5. A recloser can handle any degree of asymmetrical current. A breaker is subject to an S factor derating.
6. A *sectionalizer* is a self-contained circuit-opening device that automatically isolates a faulted portion of a distribution line from the source only after the line has been de-energized by an upline primary protective device.
7. A *power fuse* is applied close to the substation (2.8–169 kV and X/R between 15 and 25).
8. A *distribution fuse* is applied farther out on the system (5.2–38 kV and X/R between 8 and 15).
9. The *fuse tube* (in cutout) determines the interrupting capability of the fuse. There is an auxiliary tube that usually comes with the fuse that aids in low current interruption.

10. Some *expulsion fuses* can handle 100% continuous and some 150%.
11. Type “K” is a fast fuse link with a speed ratio of melting time–current characteristics from 6 to 8.1. (Speed is the ratio of the 0.1-s minimum melt current to the 300-s minimum melt current. Some of the larger fuses use the 600-s point.)
12. Type “T” is a slow fuse link with a speed ratio of melt time–current characteristics from 10 to 13.
13. After about ten fuse link operations, the *fuse holder* should be replaced.
14. *Slant ratings* can be used on grounded wye, wye, or delta systems as long as the line-to-neutral voltage of the system is lower than the smaller number and the line-to-line voltage is lower than the higher number. A slant rated cutout can withstand the full line-to-line voltage whereas a cutout with a single voltage rating could not withstand the higher line-to-line voltage.
15. *Transformer fusing*—25 at 0.01; 12 at 0.1; 3 at 10 s.
16. *Unsymmetrical transformer connections (delta/wye)*

Fault Type	Multiplying Factor
Three-phase	N
Phase-to-phase	$87 (N)$
Phase-to-ground	$1.73 (N)$

where N is the ratio of $V_{\text{primary}}/V_{\text{secondary}}$.

17. Multiply the high side device *current points* by the appropriate factor.
18. *K factor for load side fuses*
 - a. Two fast operations and dead time 1–2 s = 1.35.
19. *K factor for source side fuses*
 - a. Two fast—Two delayed and dead time of 2 s = 1.7.
 - b. Two fast—Two delayed and dead time of 10 s = 1.35.
 - c. Sometimes these factors go as high as 3.5 so check.
20. *Sequence coordination*—Achievement of true “trip coordination” between an upline electronic recloser and a downline recloser is made possible through a feature known as “sequence” coordination. Operation of sequence coordination requires that the upline electronic recloser be programmed with “fast curves” whose control response time is slower than the clearing time of the downline recloser fast operation, through the range of fault currents within the reach of the upline recloser. Assume a fault beyond the downline recloser that exceeds the minimum trip setting of both reclosers. The downline recloser trips and clears before the upline recloser has a chance to trip. However, the upline control does see the fault and the subsequent cutoff of fault current. The sequence coordination feature then advances its control through its fast operation, such that both controls are at their second operation, even though only one of them has actually tripped. Should the fault persist, and a second fast trip occur, sequence coordination repeats the procedure. Sequence coordination is active only on the programmed fast operations of the upline recloser. In effect, sequence coordination maintains the downline recloser as the faster device.
21. *Recloser time–current characteristics*
 - a. Some curves are average. Maximum is 10% higher.
 - b. Response curves are the responses of the sensing device and do not include arc extinction.
 - c. Clearing time is measured from fault initiation to power arc extinction.
 - d. The response time of the recloser is sometimes the only curve given. To obtain the interrupting time, you must add approximately 0.045 s to the curve (check... they are different).
 - e. Some curves show maximum clearing time. On the new electronic reclosers, you usually get a control response curve and a clearing curve.
 - f. $Z_{\ell} - g = (2Z_1 + Z_0)/3$
22. The “75% Rule” considers TCC tolerances, ambient temperature, pre-loading, and pre-damage. Pre-damage only uses 90%.

23. A *back-up CLF* with a designation like “12 K” means that the fuse will coordinate with a K link rated 12 A or less.
24. *Capacitor Fusing*:
 - a. The 1.35 factor may result in nuisance fuse operations. Some utilities use 1.65.
 - b. Case rupture is not as big a problem as years ago due to all film designs.
 - c. Tank rupture curves may be probable or definite in nature. Probable means there is a probability chance of not achieving coordination. Definite indicates there is effectively no chance of capacitor tank rupture with the proper 0% probability curve.
 - d. T links are generally used up to about 25 A and K link above that to reduce nuisance fuse operations from lightning.
25. *Line Impedance*—Typical values for line impedance (350 kcm) on a per mile basis are as follows:

	Z_{positive}	Z_0
Cable UG	$0.31 + j0.265$	$1.18 + j0.35$
Spacer	$0.3 + j0.41$	$1.25 + j2.87$
Tree wire	$0.3 + j0.41$	$1.25 + j2.87$
Armless	$0.3 + j0.61$	$0.98 + j2.5$
Open	$0.29 + j0.66$	$0.98 + j2.37$

26. 1A–3B is necessary when sectionalizers are used downstream from the recloser.
27. Vacuum reclosers have interrupting ratings as high as 10–20 kA.
28. Highest recloser continuous ratings are 800 and 1200 A.
29. Sectionalizer actuating current should be <80% of back-up device trip current.
30. Interrupting ratings of cutouts are approximately 7–10 kA symmetrical.
31. *K factor* can mean a “voltage range” factor or a “shift factor” caused by the recloser heating up the fuse.
32. *Sectionalizer counts* should normally be one count less than the operations to lockout of the breaker or recloser.
33. *Sectionalizer memory* time must be greater than cumulative trip and recloser time.
34. Fuses melt at about 200% of rating.
35. Sectionalizers have momentary ratings for 1 and 10 s.
36. *Twenty five percent rule* for fuses includes pre-load, ambient temperature, and pre-damage.
37. **Characteristics of Chance Sectionalizers include:**
 - 100 A continuous
 - 160 A actuating
 - 2 counts
 - 12,000 A momentary
 - 4,000 A at 1 s
 - 2,500 A at 10 s
 - 0.3 A detector threshold
 - Minimum time delay = 80 ms
 - Reset time approximately 25 s
 - Minimum duration of current impulse approximately 1–3 cycles
 - *Short time curves* are 20% of the normal curve (in time)
 - *Long time curves* are ten times the normal

23.1.10 Capacitor Fusing

1. Purpose of fusing:
 - a. To isolate faulted bank from system
 - b. To protect against bursting

- c. To give indication
 - d. To allow manual switching (fuse control)
 - e. To isolate faulted capacitor from bank
2. Recommended rating:
 - a. The continuous-current capability of the fuse should be at least 165% of the normal capacitor bank (for delta and floating wye banks the factor may be reduced to 150% if necessary).
 - b. The total clearing characteristics of the fuse link must be coordinated with the capacitor “case bursting” curves.
 3. Tests have shown that expulsion fuse links will not satisfactorily protect against violent rupture where the fault current through the capacitor is greater than 5000 A.
 4. The capacitor bank may be connected in a floating wye to limit short-circuit current to less than 5000 A.
 5. *Inrush*—for a single bank, the inrush current is always less than the short-circuit value at the bank location.
 6. *Inrush*—for parallel banks, the inrush current is always much greater than for a single bank.
 7. *Expulsion fuses* offer the following advantages:
 - a. They are inexpensive and easily replaced
 - b. They offer a positive indication of operation
 8. *CLFs* are used where:
 - a. a high available short circuit exceeds the expulsion or non-vented fuse rating.
 - b. a CLF is needed to limit the high energy discharge from adjacent parallel capacitors effectively.
 - c. a non-venting fuse is needed in an enclosure.
 9. The fuse link rating should be such that the link will melt in 300 s at 240–350% of normal load current.
 10. The fuse link rating should be such that it melts in 1 s at not over 220 A and in 0.015 s at not over 1700 A.
 11. The fuse rating must be chosen through the use of melting time–current characteristic curves, because fuse links of the same rating, but of different types and makes have a wide variation in the melting time at 300 s and at high currents.
 12. *Safe zone*—usually greater damage than a slight swelling.
 - a. *Zone 1*—suitable for locations where case rupture or fluid leakage would present no hazard.
 - b. *Zone 2*—suitable for locations that have been chosen after careful consideration of possible consequences associated with violent case ruptures.
 - c. *Hazardous zone*—unsafe for most applications. The case will often rupture with sufficient violence to damage adjacent units.
 13. Manufacturers normally recommend that the group fuse size be limited by the 50% probability curve or the upper boundary of Zone 1.
 14. Short-circuit current in an open wye bank is limited to approximately three times the normal current.
 15. CLFs can be used for delta or grounded wye banks, provided there is sufficient short-circuit current to melt the fuse within $\frac{1}{2}$ cycle.

23.1.11 Conductor Burndown

Conductor burndown is a function of (i) conductor size, (ii) whether the wire is bare or covered, (iii) the magnitude of the fault current, (iv) climatic conditions such as wind, and (v) the duration of the fault current.

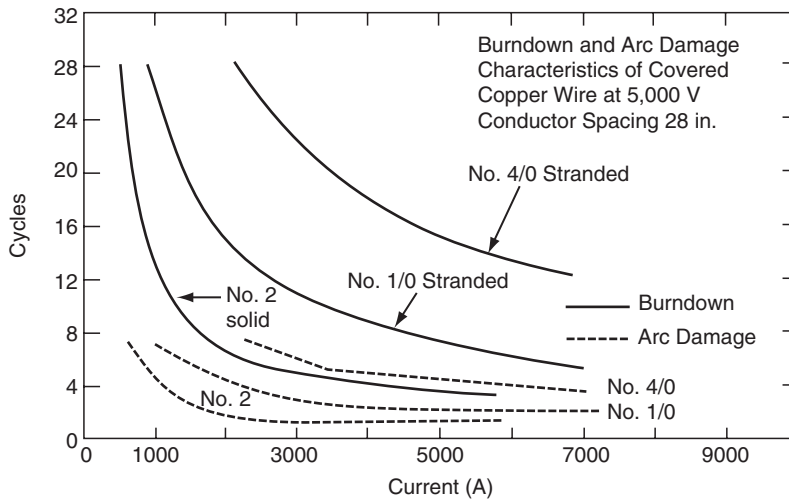


FIGURE 23.9 Burndown characteristics of several weatherproof conductors.

If burndown is less of a problem today than in years past, it must be attributed to the trend of using heavier conductors and a lesser use of covered conductors. However, extensive outages and hazards to life and property still occur as the result of primary lines being burned down by flashover, tree branches falling on lines, etc. Insulated conductors, which are used less and less, anchor the arc at one point and thus are the most susceptible to being burned down. With bare conductors, except on multi-grounded neutral circuits, the motoring action of the current flux of an arc always tends to propel the arc along the line away from the power source until the arc elongates sufficiently to automatically extinguish itself. However, if the arc encounters some insulated object, the arc will stop traveling and may cause line burndown.

With tree branches falling on bare conductors, the arc may travel away and clear itself; however, the arc will generally reestablish itself at the original point and continue this procedure until the line burns down or the branch falls off the line. Limbs of soft spongy wood are more likely to burn clear than hard wood. However $\frac{1}{2}$ -in. diameter branches of any wood, which cause a flashover, are apt to burn the lines down unless the fault is cleared quickly enough.

Figure 23.9 shows the burndown characteristics of several weatherproof conductors. Arc damage curves are given as arc is extended by traveling along the phase wire; it is extinguished but may be reestablished across the original path. Generally, the neutral wire is burned down.

23.1.12 Protective Device Numbers

The devices in the switching equipment are referred to by numbers, with appropriate suffix letters (when necessary), according to the functions they perform. These numbers are based on a system that has been adopted as standard for automatic switchgear by the American Standards Association ([Table 23.1](#)).

23.1.13 Protection Abbreviations

- CS—Control switch
- X—Auxiliary relay
- Y—Auxiliary relay
- YY—Auxiliary relay
- Z—Auxiliary relay

TABLE 23.1 Protective Device Numbers

Device No.	Function and Definition
11	<i>Control power transformer</i> is a transformer that serves as the source of AC control power for operating AC devices.
24	<i>Bus-tie circuit breaker</i> serves to connect buses or bus sections together.
27	<i>AC undervoltage relay</i> is one which functions on a given value of single-phase AC under voltage.
43	<i>Transfer device</i> is a manually operated device that transfers the control circuit to modify the plan of operation of the switching equipment or of some of the devices.
50	<i>Short-circuit selective relay</i> is one which functions instantaneously on an excessive value of current.
51	<i>AC overcurrent relay</i> (inverse time) is one which functions when the current in an AC circuit exceeds a given value.
52	<i>AC circuit breaker</i> is one whose principal function is usually to interrupt short-circuit or fault currents.
64	<i>Ground protective relay</i> is one which functions on failure of the insulation of a machine, transformer, or other apparatus to ground. This function is, however, not applied to devices 51N and 67N connected in the residual or secondary neutral circuit of current transformers.
67	<i>AC power directional or AC power directional overcurrent relay</i> is one which functions on a desired value of power flow in a given direction or on a desired value of overcurrent with AC power flow in a given direction.
78	<i>Phase-angle measuring relay</i> is one which functions at a predetermined phase angle between voltage and current.
87	<i>Differential current relay</i> is a fault-detecting relay that functions on a differential current of a given percentage or amount.

1. To denote the location of the main device in the circuit or the type of circuit in which the device is used or with which it is associated, or otherwise identify its application in the circuit or equipment, the following are used:

N—Neutral

SI—Seal-in

2. To denote parts of the main device, the following are used:

H—High set unit of relay

L—Low set unit of relay

OC—Operating coil

RC—Restraining coil

TC—Trip coil

3. To denote parts of the main device such as auxiliary contacts that move as part of the main device and are not actuated by external means. These auxiliary switches are designated as follows:

“a”—closed when main device is in energized or operated position

“b”—closed when main device is in de-energized or non-operated position

4. To indicate special features, characteristics, the conditions when the contacts operate, or are made operative or placed in the circuit, the following are used:

A—Automatic

ER—Electrically reset

HR—Hand rest

M—Manual

TDC—Time-delay closing

TDDO—Time-delay dropping out

TDO—Time-delay opening

To prevent any possible conflict, one letter or combination of letters has only one meaning on individual equipment. Any other words beginning with the same letter are written out in full each time, or some other distinctive abbreviation is used.

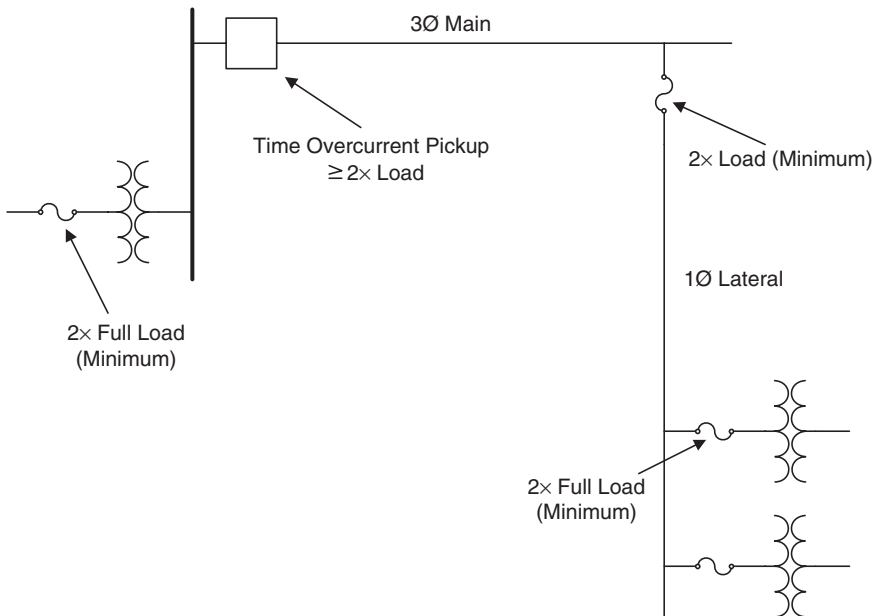


FIGURE 23.10 Burke 2× rule.

23.1.14 Simple Coordination Rules

There are few things more confusing in distribution engineering than trying to find out rules of overcurrent coordination, i.e., what size fuse to pick or where to set a relay, etc. The patented (*just kidding*) Burke 2× rule states that when in doubt, pick a device of twice the rating of what it is you are trying to protect as shown in Fig. 23.10. This rule picks the minimum value you should normally consider and is generally as good as any of the much more complicated approaches you might see. For various reasons, you might want to go higher than this, which is usually okay. To go lower, you will generally get into trouble. One exception to this rule is the fusing of capacitors where minimum size fusing is important to prevent case rupture.

23.1.15 Lightning Characteristics

1. Stroke currents
 - a. Maximum—220,000 A
 - b. Minimum—200 A
 - c. Average—10,000–15,000 A
2. Rise times—1–100 μ s
3. Lightning polarity—approximately 95% are negative
4. Annual variability (Empire State Building)
 - a. Maximum number of hits—50
 - b. Average—21
 - c. Minimum—3
5. Direct strokes to T line—one per mile per year with keraunic levels between 30 and 65
6. Lightning discharge currents in distribution arresters on primary distribution lines (composite of urban and rural)

Maximum measured to date—approximately 40,000 A

1% of records at least 22,000 A

TABLE 23.2 Lightning Discharge Current vs. Location

Col. 1	Col. 2	Col. 3	Col. 4
Urban Circuits (%)	Semi-urban Circuits (%)	Rural Circuits (%)	Discharge Currents (A)
20	35	45	1,000
1.6	7	12	5,000
0.55	3.5	6	10,000
0.12	0.9	2.4	20,000
		0.4	40,000

5% of records at least 10,500 A

10% of records at least 6,000 A

50% of records at least 1,500 A

7. Percent of distribution arresters receiving lightning currents at least as high as in Col. 4 in Table 23.2.
8. Number of distribution arrester operations per year (excluding repeated operations on multiple strokes):
 - a. Average on different systems—0.5 to 1.1 per year
 - b. Maximum recorded—6 per year
 - c. Maximum number of successive operations of one arrester during one multiple lightning stroke—12 operations

23.1.16 Arc Impedance

Although arcs are quite variable, a commonly accepted value for currents between 70 and 20,000 A has been an arc drop of 440 V/ft, essentially independent of current magnitude:

$$Z_{\text{arc}} = 440l/I \quad l = \text{length of arc (in feet)} \quad I = \text{current}$$

Assume:

$$I_F = 5000 \text{ A} = I$$

Arc length = 2 ft.

$$Z_{\text{arc}} = 440 \times (2/5000) = 0.176 \, \Omega \quad \therefore \text{Arc impedance is pretty small.}$$

Let us say you have a 120 V secondary fault and the distance between the phase and neutral is 1 ft. If the current level was 500 A then the arc resistance would be $(440 \times 1)/500 = 0.88 \, \Omega$, which is significant in its effect on fault levels.

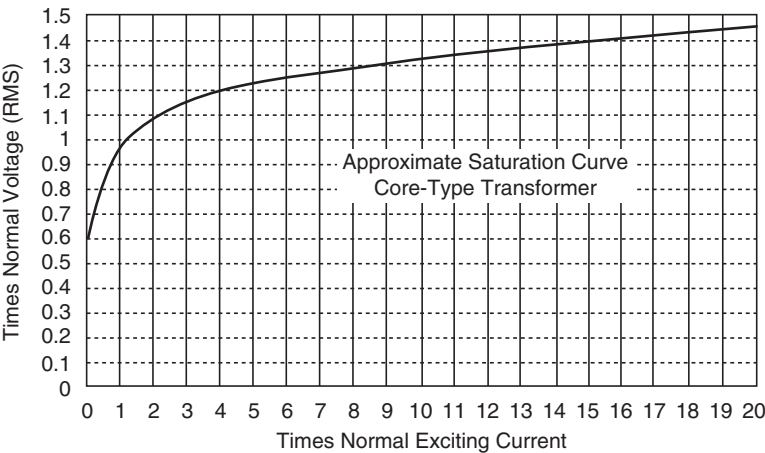


FIGURE 23.11 Transformer saturation curve.

TABLE 23.3 Insulation Levels for Transformer Windings and Bushings

Insulation Class and Nominal Bushing Rating kV	Low-frequency Dielectric Tests kV	Windings			Bushings		
		Impulse Tests (1.2×50 Wave)			Bushing Withstand Voltages		
		Chopped Wave					
		Minimum Time to Flashover		Full Wave kV	60-cycle 1-min Dry kV (Rms)	60-cycle 10-s Wet kV (Rms)	Impulse 1.2×50 Wave kV (Crest)
		kV	μs				
1.2	10	36	1.0	10	10	6	30
5.0	19	69	1.5	60	21	20	60
8.66	26	88	1.6	75	27	24	75
15.0	34	110	1.8	95	35	30	95
25.0	40	145	1.9	125	70	60	150
34.5	70	175	3.0	150	95	95	200
46.0	95	290	3.0	250	120	120	250
69.0	140	400	3.0	350	175	175	350

23.2 Transformers

23.2.1 Saturation Curve

See Figure 23.11.

23.2.2 Insulation Levels

Table 23.3 gives the American standard test levels for insulation of distribution transformers.

23.2.3 Δ -Y Transformer Banks

Figure 23.12 is a review of fault current magnitudes for various secondary faults on a Δ -Y transformer bank connection.

23.2.3.1 Transformer Loading

When the transformer is overloaded, the high temperature decreases the mechanical strength and increases the brittleness of the fibrous insulation. Even though the insulation strength of the unit may not be seriously decreased, transformer failure rate increases due to this mechanical brittleness.

- Insulation life of the transformer is where it loses 50% of its tensile strength. A transformer may continue beyond its predicted life if it is not disturbed by short-circuit forces, etc.
- The temperature of top oil should never exceed 100°C for power transformers with a 55° average winding rise insulation system. Oil overflow or excessive pressure could result.
- The temperature of top oil should not exceed 110°C for those with a 65°C average winding rise.
- Hotspot should not exceed 150°C for 55°C systems and 180°C for 65°C systems. Exceeding these temperature could result in free bubbles that could weaken dielectric strength.
- Peak short duration loading should never exceed 200%.
- Standards recommend that the transformer should be operated for normal life expectancy. In the event of an emergency, a 2.5% loss of life per day for a transformer may be acceptable.
- Percent Daily Load for Normal Life Expectancy with 30°C Cooling Air (see Table 23.4).

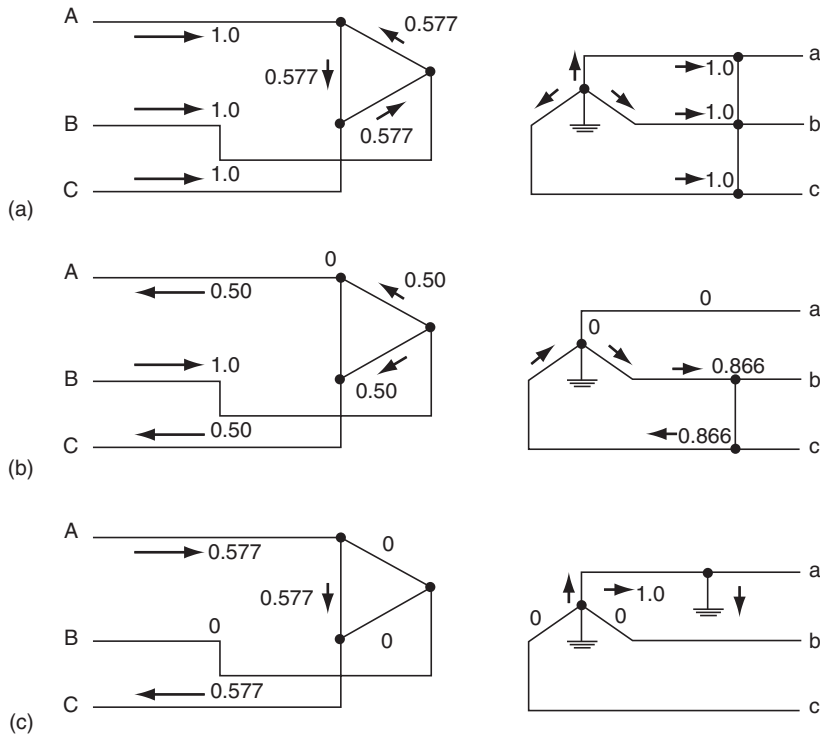


FIGURE 23.12 Δ-Y transformer banks.

TABLE 23.4 Distribution Transformer Overload with Normal Loss of Life

Duration of Peak Load (Hours)	Self-cooled with % Load before Peak of:		
	50	70	90
0.5	189	178	164
1	158	149	139
2	137	132	124
4	119	117	113
8	108	107	106

23.3 Instrument Transformers

23.3.1 Two Types

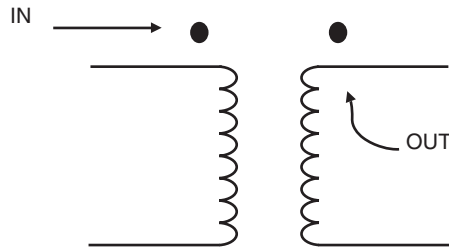
1. Potential (usually 120 V secondary)
2. Current (5 A secondary at rated primary current)

23.3.2 Accuracy

Three factors will influence accuracy:

1. Design and construction of transducer
2. Circuit conditions (V , I , and f)
3. Burden (in general, the higher the burden, the greater the error)

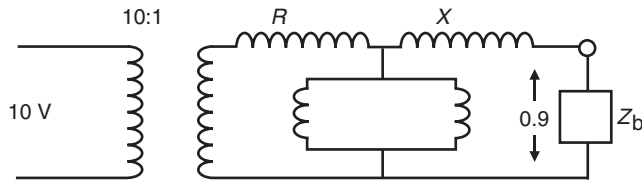
23.3.3 Potential Transformers



$$\text{Ratio correction factor (RCF)} = \frac{\text{true ratio}}{\text{marked ratio}} \quad (\text{RCF generally} > 1)$$

$$\text{Burden is measured in VA} \quad \therefore \text{VA} = \frac{E^2}{Z_b}$$

Assume



$$\text{True ratio} = \frac{10}{0.9} = 11.1$$

$$\Rightarrow \text{RCF} = \frac{11.1}{10} = 1.11$$

$$\text{Marked ratio} = \frac{10}{1} = 10$$

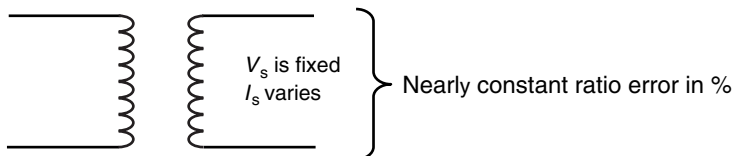
Voltage at secondary is low and must be compensated by 11% to get the actual primary voltage using the marked ratio.

23.3.4 Current Transformer

$$\text{True ratio} = \text{marked ratio} \times \text{RCF}$$

$$\therefore \text{RCF} = \frac{\text{true ratio}}{\text{marked ratio}}$$

23.3.5 H-Class



Burdens are in series

e.g., 10H200 $\Rightarrow$ 10% error at 200 V

$$\therefore 20 (5 \text{ As}) = 100 \text{ A} \Rightarrow Z_b = 200/100 = 2 \Omega$$

$$\Rightarrow 5 \text{ A to } 100 \text{ A has } \leq 10\% \text{ error if } Z_b = 4 \Omega$$

or

If $Z_b = 4 \Omega$

$$200 \text{ V}/4 \Omega = 50 \text{ A (ten times normal)}$$

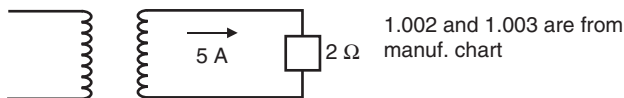
H-class—constant magnitude error (variable %)

L-class—constant % error (variable magnitude)

Example

True ratio = marked ratio $\times$ RCF

Assume marked is 600/5 or 120:1 at rated amps and 2Ω



At 100% A true = $120 \times 1.002 \times 5$ secondary

primary = $600 \times 1.002 = 601.2$

At 20% A true = $600 \times 0.2 \times 1.003 = 120.36$ (marked was 120)

23.3.6 Current Transformer Facts

1. Bushing current transformers (BCTs) tend to be accurate more on high currents (due to large core and less saturation) than other types.
2. At low currents, BCTs are less accurate due to their larger exciting currents.
3. Rarely, if ever, it is necessary to determine the phase-angle error.
4. Accuracy calculations need to be made only for three-phase and single-phase to ground faults.
5. CT burden decreases as secondary current increases, because of saturation in the magnetic circuits of relays and other devices. At high saturation, the impedance approaches the DC resistance.
6. It is usually sufficiently accurate to add series burden impedance arithmetically.
7. The reactance of a tapped coil varies as the square of the coil turns, and the resistance varies approximately as the turns.
8. Impedance varies as the square of the pickup current.
9. Burden impedances are always connected in wye.
10. "Ratio correction factor" is defined as that factor by which the marked ratio of a current transformer must be multiplied to obtain the true ratio. These curves are considered standard application data.
11. The secondary-excitation-curve method of accuracy determination does not lend itself to general use except for bushing-type, or other, CTs with completely distributed secondary leakage, for which the secondary leakage reactance is so small that it may be assumed to be zero.
12. The curve of rms terminal voltage vs. rms secondary current is approximately the secondary-excitation curve for the test frequency.
13. ASA accuracy classification:
 - a. This method assumes CT is supplying 20 times its rated secondary current to its burden.
 - b. The CT is classified on the basis of the maximum rms value of voltage that it can maintain at its secondary terminals without its ratio error exceeding a specified amount.

- c. “H” stands for high internal secondary impedance.
- d. “L” stands for low internal secondary impedance (bushing type).
- e. 10H800 means the ratio error is 10% at 20 times rated voltage with a maximum secondary voltage of 800 and high internal secondary impedance.
- f. Burden (max)—maximum specified voltage/ $20 \times$ rated second.
- g. The higher the number after the letter, the better the CT.
- h. A given 1200/5 bushing CT with 240 secondary turns is classified as 10L400: if a 120-turn completely distributed tap is used, then the applicable classification is 10L200.
- i. For the same voltage and error classifications, the H transformer is better than the L for currents up to 20 times rated.

23.3.7 Glossary of Transducer Terms

Voltage transformers—They are used whenever the line voltage exceeds 480 V or whatever lower voltage may be established by the user as a safe voltage limit. They are usually rated on a basis of 120 V secondary voltage and used to reduce primary voltage to usable levels for transformer-rated meters.

Current transformers—Current transformers are usually rated on a basis of 5 A secondary current and used to reduce primary current to usable levels for transformer-rated meters and to insulate and isolate meters from high-voltage circuits.

Current transformer ratio—Current transformer ratio is the ratio of primary to secondary current. For current transformer rated 200:5, the ratio is 200:5 or 40:1.

Voltage transformer ratio—Voltage transformer ratio is the ratio of primary to secondary voltage. For voltage transformer rated 480:120, the ratio is 4:1, 7200:120, or 60:1.

Transformer ratio (TR)—Transformer ratio is the total ratio of current and voltage transformers. For 200:5 CT and 480:120 PT, $TR = 40 \times 4 = 160$.

Weatherability—Transformers are rated as indoor or outdoor, depending on construction (including hardware).

Accuracy classification—Accuracy classification is the accuracy of an instrument transformer at specified burdens. The number used to indicate accuracy is the maximum allowable error of the transformer for specified burdens. For example, 0.3 accuracy class means the maximum error will not exceed 0.3% at stated burdens.

Rated burden—Rated burden is the load that may be imposed on the transformer secondaries by associated meter coils, leads, and other connected devices without causing an error greater than the stated accuracy classification.

Current transformer burdens—Current transformer burdens are normally expressed in ohms impedance such as B-0.1, B-0.2, B-0.5, B-0.9, or B-1.8. Corresponding volt-ampere values are 2.5, 5.0, 12.5, 22.5, and 45.

Voltage transformer burdens—Voltage transformer burdens are normally expressed as volt-amperes at a designated power factor. May be W, X, M, Y, or Z where W is 12.5 VA at 0.10 pf, X is 25 VA at 0.70 pf, M is 35 VA at 0.20 pf, Y is 75 VA at 0.85 pf, and Z is 200 VA at 0.85 pf. The complete expression for a current transformer accuracy classification might be 0.3 at B-0.1, B-0.2, and B-0.5, while the potential transformer might be 0.3 at W, X, M, and Y.

Continuous thermal rating factor (TRF)—Continuous TRF is normally designated for current transformers and is the factor by which the rated primary current is multiplied to obtain the maximum allowable primary current without exceeding temperature rise standards and accuracy requirements. For example, if a 400:5 CT has a TRF of 4.0, the CT will continuously accept 400×4 or 1600 primary amperes with 5×4 or 20 A from the secondary. The thermal burden rating of a voltage transformer shall be specified in terms of the maximum burden in volt-amperes that the transformer can carry at rated secondary voltage without exceeding a given temperature rise.

Rated insulation class—Rated insulation class denotes the nominal (line-to-line) voltage of the circuit on which it should be used. Associated Engineering Company has transformers rated for 600 V through 138 kV.

Polarity—The relative polarity of the primary and secondary windings of a current transformer is indicated by polarity marks (usually white circles), associated with one end of each winding. When current enters at the polarity end of the primary winding, a current in phase with it leaves the polarity end of the secondary winding. Representation of primary marks on wiring diagrams is shown as black squares.

Hazardous open circulating—The operation of CTs with the secondary winding open can result in a high voltage across the secondary terminals, which may be dangerous to personnel or equipment. Therefore, the secondary terminals should always be short circuited before a meter is removed from service. This may be done automatically with a bypass in the socket or by a test switch for A-base meters.

23.4 Loading

Probably no area of distribution engineering causes more confusion than does loading. Reading the standards does not seem to help much since everyone appears to have their own interpretation. Manufacturers of equipment are very conservative since they really never know how the user will actually put the product to use so they must expect the worst. On the other hand, many users seem to take the approach that since it did not fail last year with traditional overloading values, it will not fail this year either. In fact, it will not fail until after retirement. Heck! “Save a buck and get a promotion.” The author of this document is not a psychology major and frankly has no idea of what the thinking was when much of the following was produced. The material that follows, however, was taken from sources with excellent reputation. Use it with caution.

23.4.1 Transformer Loading Basics

- All modern transformers have insulation systems designed for operation at 65°C average winding temperature and 80°C hottest-spot winding rise over ambient in an average ambient of 30°C. This means:
 - 65°C average winding rise + 30°C ambient = 95°C average winding temperature
 - 80°C hottest-spot rise + 30°C ambient = 110°C hottest spot



- (Old system: 55°C winding rise + 30°C ambient = 85°C average winding temperature)
- 65°C hottest spot + 30°C ambient = 95°C hottest spot
 - Notice that 95°C is the average winding temperature for the new insulation system and the hottest spot for the old—A source of immense confusion for many of us.
 - The temperature of the top oil should not exceed 100°C. Obviously, top-oil temperature is always less than hottest spot.
 - The maximum hotspot temperature should not exceed 150°C for a 55°C rise transformer or 180°C for a 65°C rise transformer.
 - Peak 0.5 h loading should not exceed 200%.
 - The conditions of 30°C ambient temperature and 100% load factor establish the basis of transformer ratings.
 - The ability of the transformer to carry more than nameplate rating under certain conditions without exceeding 95°C is basically due to the fact that top-oil temperature does not instantaneously follow changes in transformer load due to thermal storage.

- An average loss of life of 1% per year (or 5% in any emergency) incurred during emergency operations is considered reasonable.
- Most companies do not allow normal daily peaks to exceed the permissible load for normal life expectancy.
- The firm capacity is usually the load that the substation can carry with one supply line or one transformer out of service.
- “Emergency 24-h firm capacity” usually means a loss of life of 1% but is sometimes as much as 5% or 6%.
- The following measures can be used for emergency conditions lasting more than 24 h:
 - Portable fans
 - Water spray
 - Interconnect cooling equipment of FOA units
 - Use transformer thermal relays to drop certain loads

23.4.2 Examples of Substation Transformer Loading Limits

The following is an example of maximum temperature limits via the IEEE for a 65°C rise transformer:

IEEE Normal Life Expectancy	
Top-oil temperature	105°C
Hotspot temperature	120°C

This next example shows the loading practice of various utilities for substation transformers:

	Utility A	Utility B	Utility C	Utility D	Utility E	Utility F	Utility G
Normal Conditions							
Top-oil	95	110	95	95	95	110	110
Hotspot	125	130	120	110	120	140	120
Emergency Conditions							
Top-oil	110	110	110	110	110	110	110
Hotspot	140	140	140	130	140	140	140

What happens when the hotspot is raised from 125°C to 130°C? This is shown as follows:

Maximum Hotspot (°C)	% Loss of Life, Annual
125	0.3366
130	0.5372

An example of the effect of load cycle (3-h peak with 70% pre-load for 13 h and 45% load for 8 h) and ambient on transformer capability via the ANSI guide is shown below:

Transformer Type	Peak Load for Normal Life Expectancy		Emergency Peak Load with 24-h Loss of Life	
	10°C Ambient	30°C Ambient	0.25%	1.0%
20,000—OA	30,000	24,200	28,400	32,000
15,000/2,000—OA/FA	28,700	23,800	27,500	30,700
12,000/16,000/ 20,000—OA/FA/FOA	27,500	23,200	26,800	29,700
20,000—FOA	27,500	23,200	26,800	29,700

The following is the effect on transformer ratings for various limits of top-oil temperature:

	MVA	Top-Oil Temperature (°C)
Normal rating	50	95
New rating	55	105
Emergency rating	59	110

23.4.3 Distribution Transformers

The loading of distribution transformers varies more widely than substation units. Some utilities try to never exceed the loading of the transformer nameplate. Others, particularly those using TLM, greatly overload smaller distribution transformers with no apparent increase in failure rates. An example of one utilities practice is as follows:

kVA	Padmounted		Submersible	
	Install Range	Removal Point	Install Range	Removal Point
25	0–40	55	0–34	42
50	41–69	88	35–64	79
75	70–105	122	65–112	112
100	106–139	139	113–141	141

23.4.4 Ampacity of Overhead Conductors

The table below shows the rating of conductors via a typical utility:

Conductor Size	ACSR		All Aluminum	
	Normal	Emergency	Normal	Emergency
1/0	319	331	318	334
2/0	365	379	369	388
3/0	420	435	528	450
4/0	479	496	497	523
267	612	641	576	606
336	711	745	671	705
397	791	830	747	786

23.4.5 Emergency Ratings of Equipment

The following are some typical 2-h overload ratings of various substation equipment. Use at your own risk:

Station transformer	140%
Current transformer	125%
Breakers	110%
Reactors	140%
Disconnects	110%
Regulators	150%

23.5 Miscellaneous Loading Information

The following are some miscellaneous loading information and thoughts from a number of actual utilities:

a. Commercial and industrial transformer loading

Load Factor (%)	Transformer Load Limit (%)
0–64	130
65–74	125
75–100	120

b. Demand factor

Lights—50%

Air conditioning—70%

Major appliances—40%

c. Transformer loading

- Distribution transformer life is in excess of five times the present guide levels.
- Distribution guide shows that life expectancy is about 500,000 h for 100°C hottest-spot operation, compared to 200,000 h for a power transformer. Same insulation system.
- Using present loading guides, only 2.5% of power transformer thermal life is used up after 15 years.
- Results of one analysis showed that the transition from acceptable to unacceptable risk (approximately an order of magnitude) was accompanied (by this utility) by only an 8.5% investment savings and a 12% increase in transformer loading.
- Application of transformers in *excess of normal loading* can cause the following:
 - Evolution of *free gas* from insulation of winding and lead conductors.
 - Evolution of free gas from insulation adjacent to metallic structural parts linked by magnetic flux produced by winding or lead currents may also reduce dielectric strength.
 - Operation at high temperatures will cause *reduced mechanical strength* of both conductor and structural insulation.
 - Thermal expansion of conductors, insulation materials, or structural parts at high temperature may result in permanent *deformations* that could contribute to mechanical or dielectric failures.
 - *Pressure buildup in bushings* for currents above rating could result in leaking gaskets, loss of oil, and ultimate dielectric failure.
 - *Increased resistance in the contacts* of tap changers can result from a buildup of oil decomposition products in a very localized high temperature region.
 - Reactors and current transformers are also at risk.
 - *Oil expansion* could become greater than the holding capacity of the tank.
- *Aging or deterioration of insulation* is a time function of temperature, moisture content, and oxygen content. With modern oil preservation systems, the moisture and oxygen contributions to insulation deterioration can be minimized, leaving insulation temperature as the controlling parameter.
- Distribution and power transformer model tests indicate that the *normal life expectancy* at a continuous hottest-spot temperature of 110°C is 20.55 years.
- Input into *a transformer loading program* should be as follows:
 - Transformer characteristics (loss ratio, top-oil rise, hottest-spot rise, total loss, gallons of oil, and weight of tank and fittings)
 - Ambient temperatures
 - Initial continuous load

- Peak load durations and the specified daily percent loss of life
- Repetitive 24-h load cycle if desired
- *Maximum permitted loading* is 200% for a power transformer and 300% for a distribution transformer.
- Suggested limits of *loading for distribution transformers* are as follows:
 - Top oil—120°C
 - Hottest spot—200°C
 - Short time (0.5 h)—300%
- Suggested *limits for power transformers* are as follows:
 - Top oil—100°C
 - Hottest spot—180°C
 - Maximum loading—200%
- Overload limits for *coordination of bushings* with transformers are as follows:
 - Ambient air—40°C maximum
 - Transformer top oil—110°C maximum
 - Maximum current—two times bushing rating
 - Bushing insulation hottest spot—150°C maximum
- Current ratings for the *load tap changer (LTC)* are:
 - Temperature rise limit of 20°C for any current carrying contact in oil when carrying 1.2 times the maximum rated current of the LTC
 - Capable of 40 breaking operations at twice the rate current and kVA
- Planned *loading beyond nameplate* rating defines a condition wherein a transformer is so loaded that its hottest-spot temperature is in the temperature range of 120–130°C.
- Long term *emergency loading* defines a condition wherein a power transformer is so loaded that its hottest-spot temperature is in the temperature range of 120–140°C.
- The *principal gases* found dissolved in the mineral oil of a transformer are as follows:
 - *Nitrogen*: from external atmosphere or from gas blanket over the free surface of the oil.
 - *Oxygen*: from external atmosphere.
 - *Water*: from moisture absorbed in cellulose insulation or from decomposition of the cellulose.
 - *Carbon dioxide*: from thermal decomposition of cellulose insulation.
 - *Carbon monoxide*: from thermal decomposition of cellulose insulation.
 - *Other gases*: may be present in very small amounts (e.g., acetylene) as a result of oil or insulation decomposition by overheated metal, partial discharge, arcing, etc. These are very important in any analysis of transformers, which may be in the process of failing.
- *Moisture* affects insulation strength, power factor, aging, losses, and the mechanical strength of the insulation. Bubbles can form at 140°C, which enhance the chances of partial discharge and the eventual breakdown of the insulation as they rise to the top of the insulation. If a transformer is to be overloaded, it is important to know the moisture content of the insulation, especially if it is an older transformer. Bubbles evolve fast, so temperature is important to bubble formation but not the time at that temperature. Transformer insulation with 3.5% moisture content should not be operated above nameplate for a hottest spot of 120°C. Tests have shown that the use of circulated oil for the drying process takes some time. For a processing time of 70 h the moisture content of the test transformers was reduced from 2% to 1.9% at a temperature of 50–75°C. Apparently only surface moisture was affected. A more effective method is to remove the oil and heat the insulation under vacuum.

